

Geological uncertainty and effects of depositional sequence on improved oil recovery processes

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Abstract Several emerging improved oil recovery (IOR) techniques have been proposed in the past decades with promising results. However, a systematic study of reservoir heterogeneity on these advanced processes has not yet been presented. This paper provides one of the first comparative evaluations of the effects of reservoir heterogeneity on various IOR processes from the conventional methods (waterflooding, CO₂ flooding) to the emerging recovery technologies (Low-Salinity Waterflooding and CO₂ Low-Salinity WAG) for wider and more successful implementation of these projects. Since weakness exists in the current simple and unrealistic models, detailed geostatistic models are employed to provide a more realistic and unbiased evaluation of reservoir heterogeneity. A new modeling approach that involves the integration of geological software, a reservoir simulator and a robust optimizer in a closed loop for generating multiple geologically driven realizations and uncertainty assessment of different recovery processes is introduced. Then a series of numerical simulations is conducted to investigate the influences of FU and CU sequences on oil recovery. Finally, the uncertainty range of reservoir heterogeneity is thoroughly evaluated using a large number of geological realizations with significant differences on porosity and permeability distributions. The effect of the K_v/K_h (aspect) ratio is also addressed in this study. The simulation results indicate that the depositional sequence has a dominant effect on oil recovery in all recovery processes. The CU distribution demonstrates superior performance over the FU distribution.

Keywords Geological heterogeneity · Depositional sequence · Enhanced oil recovery · Uncertainty assessment

Introduction

Improved oil recovery (IOR) methods have received increasing interest and importance because of the need to increase oil production to address global energy demands. IOR refers to any reservoir process to improve oil recovery including enhanced oil recovery (EOR) processes, such as wellbore conformance control, immiscible gas injection, and waterflooding. Although these processes can provide a high oil recovery factor, their performance strongly depends on the reservoir geology, in particular, the horizontal and vertical distribution of porosity and permeability. In many sedimentary deposits, it has been found that the main reservoir properties are distributed based on the types of facies and a depositional environment. In other words, the depositional sequence of a formation plays an important role in predicting IOR flooding performance (Dastidar et al. 2005; Lorenz et al. 1989).

It is important to achieve a comprehensive understanding of the geometry, distribution and petrophysical properties of lithofacies before determining an optimal IOR strategy. A reservoir formation is normally stratified by different heterogeneous layers in both the vertical and horizontal directions. In the vertical distribution, a reservoir formation often consists of one or more fining-/coarsening-upward sequences (FU/CU). Generally speaking, in terms of simulation, an FU or CU formation is defined as a formation with decreasing or increasing upward permeability and porosity trends.

Increasing vertical and horizontal sweep efficiency is the key to achieve the success of IOR processes, which

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strongly depends on the reservoir permeability distribution. However, most studies in the past assumed a constant permeability value for formation layers. In addition, each IOR method has its own behavior associated with a specified type of a stratified reservoir. The lithofacies and reservoir heterogeneity may result in a positive result only for an appropriate recovery method. Thus, it is necessary to evaluate the performance of these processes under various geological distributions, which is still limited from the past studies.

This study focuses on investigating the effects of horizontal heterogeneity, lithofacies, and depositional sequence on the performance of different recovery processes. We address the effect of the vertical/horizontal permeability ratio as a parameter in uncertainty analysis. A geostatistical modeling approach is employed to represent the reservoir heterogeneity by utilizing an integrated modeling approach that involves the use of geological software, a reservoir simulator, and a robust optimizer in a closed loop (Fig. 1). Using simple scripts, the geological software, under the command of the optimizer, geostatistically generates new geological realizations and updates to the reservoir simulator to perform numerical simulation.

In this study, geological models consist of nine layers and each layer has a heterogeneous porosity and permeability distribution with an FU or CU permeability trend. Then an uncertainty analysis is conducted to investigate the effect of the horizontal and vertical reservoir heterogeneity by changing variograms of porosity and permeability and the K_v/K_h ratio. Finally, the effect of reservoir heterogeneity and lithofacies is investigated and compared with

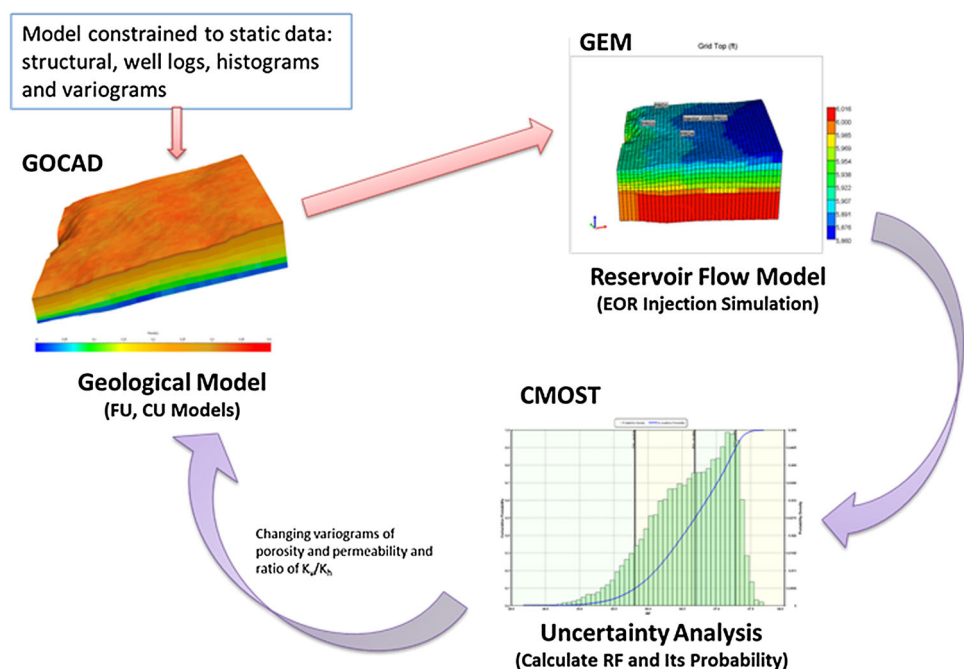
different IOR processes including waterflooding, CO₂ flooding, Low-Salinity Waterflooding (LSW) and Low-Salinity Water Alternating CO₂ (CO₂ LSWAG).

Role of geology in IOR processes

In stratified reservoirs, a variation of vertical permeability strongly affects sweep efficiency of recovery processes in terms of cross flow of injected fluids. The higher the permeability contracts between layers, the more early water breakthrough can occur during a water injection process (Sorbie and Walker 1988). Different IOR methods have been proposed to improve oil recovery and each method requires a preferable reservoir condition to be applied. This paper addresses the effect of reservoir heterogeneity on the oil recovery factor of four injection methods including conventional high-salinity waterflooding, LSW, miscible CO₂ gas flooding, and CO₂ LSWAG flooding.

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary, and tertiary. Primary production, the initial production stage, results from the displacement energy naturally existing in a reservoir. Secondary recovery, the second stage of production, is usually implemented after the primary production declines. The traditional secondary recovery process is waterflooding in which water is injected into a reservoir to obtain additional oil recovery through displacement of reservoir oil towards producing wells. Waterflooding is now accepted worldwide as a reliable and economic recovery technique and almost every significant oil field

Fig. 1 Uncertainty analysis workflow integrating G&G and flow model



that does not have a natural water drive has been, is being, or will be considered for waterflooding. Waterflooding depends on many factors, including reservoir geometry, lithology, reservoir depth, porosity, absolute permeability, continuity of reservoir rock properties, magnitude and distribution of fluid saturations, fluid properties, and relative permeability. Permadi et al. (2004) investigated the effects of vertical heterogeneity on waterflood performance and concluded that a reservoir with an increasing upward permeability trend yields better waterflood performance as compared to that of an FU trend. The crossflow improves vertical sweep efficiency of waterflood and it is more effective in CU formations. El-Khatib (2010) studied the effect of a reservoir dip angle on waterflood performance. The dip angle of a reservoir controls the gravity and delays water breakthrough, leading to increasing oil recovery and lowering water cut.

Tertiary recovery, the third stage of production, is after secondary waterflooding. Miscible CO₂ gas flooding is an important EOR technology in which CO₂ gas mobilizes and displaces residual oil using a multiple contact miscible process. This process also strongly depends on reservoir characteristics. AlAli et al. (2011) investigated the effect of gas injection in multi-layered porous media via studying the effects of viscous, gravity and capillary forces on the displacement performance in coreflood experiments. Their experiments consisted of three homogeneous layers and they found that most of the displacement took place in the high-permeable layer, not in the low-permeable layer. It was independent from the fluid system and orientation. The gravity effect is favorable and the area sweep efficiency is higher if the high-permeable layer is at the bottom. Summapo et al. (2013) also evaluated the performance of CO₂ flooding in multi-layered heterogeneous reservoirs. They concluded that the formation depositional sequence controlled the flow path of fluids in a reservoir and affected the gravity segregation of CO₂, resulting in retardation of gas breakthrough and leading to final oil recovery.

Recently, various laboratory studies and pilot tests have encouraged further investigation into the optimization of a waterflooding process through a simple modification of brine salinity. LSW is an emerging attractive EOR method because of its oil recovery performance and relatively simple, environmentally friendly implementation, when compared with conventional high-salinity waterflooding and other EOR approaches. Several authors have reported that injecting low-salinity brine can increase oil recovery by a factor up to 40 % compared with conventional high-salinity waterfloods in different sandstone reservoirs (McGuire et al. 2005). The success of LSW is due to the interactions and effects of brine, crude oil, and mineralogy on wettability (Dang et al. 2013a; Dang et al. 2015a). Thanks to the results

of coreflooding experiments, numerical simulation, and pilot tests, LSW is favorable in reservoirs that contain clay minerals. It has been found that the success of LSW in sandstone reservoirs strongly depends on the clay content, clay distribution, and the distribution of porosity and permeability (Dang et al. 2015b, c). From these studies, a medium grain size of sands is more favorable for LSW implementation compared to fine and coarse grain sands since they maximize the effect of wettability alteration and sweep efficiency. Additionally, the grain size of sandstone is strongly controlled by depositional environment.

LSW can also be combined with other EOR approaches such as miscible water alternating gas (WAG) for a higher oil recovery factor. CO₂ LSWAG injection promotes the synergy of the mechanisms underlying LSW and WAG methods (i.e., ion exchange, wettability alteration, CO₂ miscible effects and mobility control) to further enhance oil recovery (Dang et al. 2014). The unfavorable mobility of pure gas flooding results in viscous fingering, which reduces volumetric sweep efficiency. WAG helps overcome this problem, reducing a large amount of gas required for EOR projects, which is particularly important in offshore oil fields. Oil production is usually delayed in conventional CO₂ WAG processes. Although oil recovery is predicted to be higher for a WAG process compared with pure CO₂ flooding, the economics may not be favorable because of the delayed production. CO₂ LSWAG may help overcome this challenge faced with current CO₂ WAG applications. LSW can accelerate oil production in the early stage, and CO₂ WAG can help promote ion exchange and reservoir geochemical reactions that are favorable conditions for LSW. It is expected, therefore, that CO₂ LSWAG will promote the synergy of these separate process mechanisms, thereby overcoming the late production problem frequently encountered in conventional WAG. Zolfaghari et al. (2013) reported, based on a series of coreflood experiments under conditions favorable for an LSW application, that CO₂ LSWAG gave additional oil recovery of up to 18 % OOIP. These results were then validated by 1D numerical simulation (Dang et al. 2013b) and full field-scale simulation (Dang et al. 2014). However, the performance of this hybrid recovery process also depends on reservoir geology in which unfavorable geological distribution (clay, porosity, and permeability) can significantly impair the ultimate oil recovery of CO₂ LSWAG. In another study, robust optimization based on multiple geological realizations is important to capture the geological uncertainty of this process (Dang et al. 2015d).

From the above evidence, reservoir geology plays a critical role in performances of all important IOR methods and it is very important to quantify this dominant effect to achieve broader and more successful IOR applications.

Methodology

Reservoir simulation modeling

A compositional simulator (CMG-GEM from Computer Modelling Group Ltd.) is used to run simulation with the purpose of comparing the effect of depositional sequence on oil recovery processes. The model size is $40 \times 40 \times 9$ ft. The base reservoirs in this research are synthesis reservoirs, which are generated based on data given in the literature (Permadi et al. 2004). Permadi et al. stated that these simulation data represent a stratified reservoir in Bangko field, Indonesia. Additionally, they proved that oil production rates obtained from their synthesis model showed a good agreement with those of history data. Thus, the ranges of porosity and permeability were re-used to create FU and CU models in this study. We believe that these are reasonable and can be represented in a field-stratified reservoir.

Table 1 shows the fluid and reservoir properties of all simulation models. The flood model is an inverted five-spot well pattern that consists of four producers and one injector as seen in Fig. 2. All the runs are also set with the same operation conditions. The constraints for the injector and producers are as follows: (1) the minimum production bottom-hole pressure is 2588.14 psi, (2) a maximum water/LS water injection rate is 5000 bbl/d and (3) a maximum gas injection rate is 18,135,000 ft³/d.

The reservoir models consist of nine layers with an aquifer at the bottom layer. Two geological models are created with FU or CU porosity and permeability trends as seen in Fig. 3. In the CU model, the average porosity values are 0.38, 0.32, 0.27, 0.23, 0.2, 0.17, 0.13, 0.09, and 0.03 for the aquifer and, layers 1, 2, 3, 4, 5, 6, 7, and 8, respectively. In addition, the average permeability values

are 32,039, 5640, 1390, 497, 201, 83, 33, 11, and 2 mD for the aquifer and, layers 1, 2, 3, 4, 5, 6, 7, and 8, respectively. In the FU model, the average porosity and permeability values are converted from the top to bottom layers. The ranges of both porosity and horizontal permeability in these layers are definitely controlled by histograms as seen in Fig. 4. Then two reservoir simulation models are run with those two geological models and four different injection methods, and the results of simulation will be discussed in the next section.

Moreover, to study the effect of injection methods on an oil recovery factor in a reservoir containing more than one depositional sequence, two sets of porosity and permeability of each layer are chosen to build a geological model, which contains two depositional sequences (Table 2). Each sequence is defined by four layers. Four models are created as follows:

1. Model A contains a CU sequence at the top and an FU sequence at the bottom.
2. Model B reversed from model A contains an FU sequence at the top and a CU sequence at the bottom.
3. Model C contains two CU sequences.
4. Model D contains two FU sequences.

The reservoir models have the same constraints as in the above study with the reservoir containing one depositional sequence.

Uncertainty analysis workflow

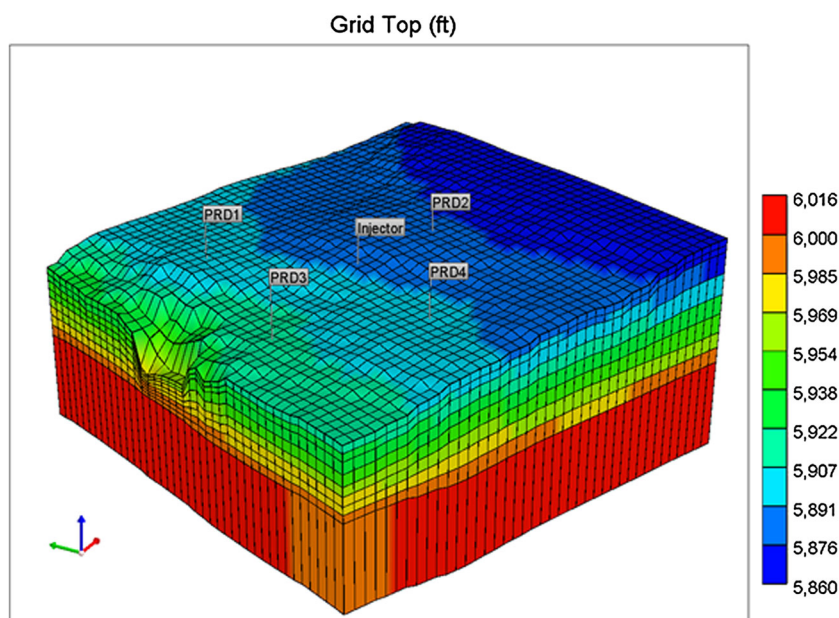
The distribution of reservoir properties such as porosity and permeability strongly controls the flow direction of displaced and displacing fluids in reservoirs. In reservoir simulation, the permeability variation of layers is characterized by a log normal distribution and the porosity variation of layers is characterized by a Gaussian distribution. The vertical heterogeneity of a reservoir is studied by changing a vertical to horizontal permeability ratio (K_v/K_h).

To continuously study the effect of the reservoir heterogeneity on IOR processes, a closed-loop uncertainty analysis process is introduced here (Fig. 1). Based on the help of a presimulation command in an optimizer (CMOST), multiple reservoir models are created by changing variograms of porosity and permeability and a K_v/K_h value. The new geological realizations by geological software (GOCAD) are generated and updated to the reservoir simulator to perform numerical simulation. Finally, CMOST will calculate new objective functions (e.g., an oil recovery factor) to evaluate the uncertainty of geology for the given reservoir model and injection method. In this uncertainty analysis process, to vary the distribution of porosity and permeability for each layer,

Table 1 Reservoir and fluid properties

Properties	Value	Unit
Model size	$40 \times 40 \times 9$	ft
Maximum reservoir thickness	156	ft
Number of layers	9	–
Aquifer	Layer 9	–
Top of reservoir	5977–5860	ft
Initial reservoir pressure	3500	psi
Initial reservoir temperature	160	F
Fluid components	7	–
Minimum Prod. BHP	2588.14	psi
Max. water injection rate	5000	bbl/d
Max. gas rate	18,135,000	ft ³ /d
Max. LS water injection rate	5000	bbl/d



Fig. 2 3D grid top model

parameters of their variograms including minimum and maximum ranges are set as uncertain parameters in CMOST. Actually changing variograms lead to a change distribution of porosity and permeability in both vertical and horizontal trends within each layer. Moreover, the ranges of porosity and permeability for each layer are controlled by histograms (min, mean, and max values) as described in Fig. 4, while the average values are constant in layers. Therefore, the permeability distribution is stratified and non-uniform in the direction of flow. Nevertheless, the layers have the same average horizontal permeability and average porosity in all generated models. The ratio of K_v/K_h is varied from 0.075 to 0.25 in the geostatistic modeling.

Results and discussion

Effect of depositional sequence on EOR processes

Reservoirs contain one depositional sequence

To investigate the effect of reservoir heterogeneity and depositional sequence, two reservoir models are generated for two FU and CU geological models. These reservoirs are heterogeneous in both the horizontal and vertical directions as described in the methodology section. Then, four injection methods are applied in these two generated reservoirs and compared for the results of simulation in terms of an oil recovery factor and water breakthrough.

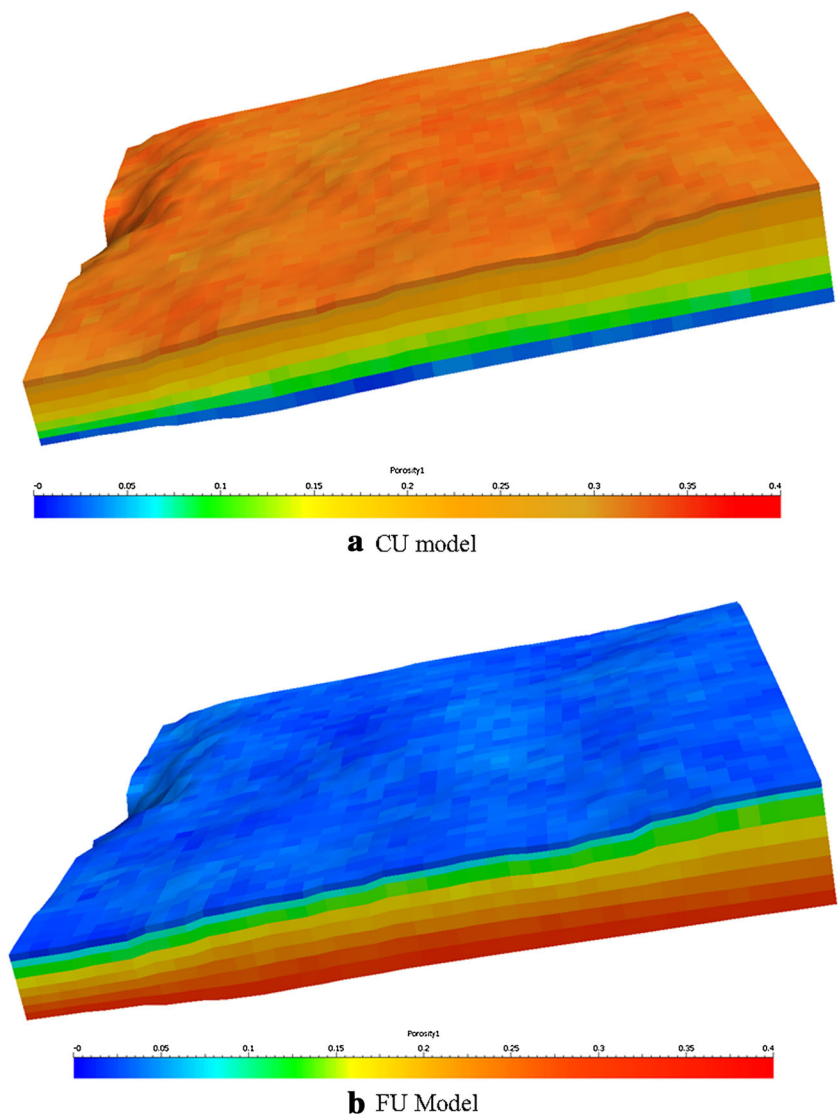
Table 3 shows oil recovery factors of the four injection methods including waterflooding, CO₂ flooding, LSW and

CO₂ LSWAG, which are applied in both the FU and CU models. The results of simulation show that the oil recovery factors of the FU model are much lower than those of the CU model. The difference is about 24.9–34.9 %. The difference between these two models is due to the different crossflow mechanisms of fluids. From these results, the depositional sequence or order of layering in the stratified reservoir has shown that it definitely plays a very important role in controlling the performance of a recovery process for all kinds of injection methods. However, it is more effective in the LSW and CO₂ LSWAG methods (34.5–34.9 %), compared to WF and CO₂ flooding (24.9–27.5 %).

Compared with WF, the increment of the oil recovery factor due to CO₂ gas flooding in the FU model (3.08 %) is higher than that in the CU model (0.48 %). Gas is light and intends to move up in the reservoir, and thus gas can move forward to the low-permeable layer at the top of the FU reservoir, which pushes more oil into the producers. For other methods, there is an inverted trend, which is found in this research. The improvement of new injection processes such as LSW and CO₂ LSWAG is higher in a CU reservoir (11–12 %) than that in an FU model (3.58–4.93 %).

As the results of simulation, water breakthrough occurs more quickly in the FU model compared to the one in the CU model (Fig. 5). In other words, the water flow rates and water production of the FU model are higher than those of the CU model and there is a large difference of the water flow rate between WF and CO₂ flooding in the FU model, but it is very small in the CU model. When reservoirs are layered with increasing permeability upward, water may go down to the lower permeable layers at the bottom due to

Fig. 3 Porosity models of FU and CU reservoirs



the gravity force, leading to reducing a water flow rate, increasing an oil flow rate and, finally, improving an oil recovery factor.

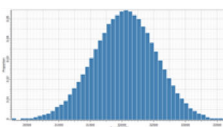
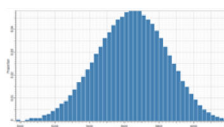
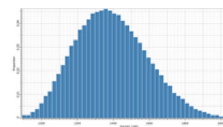
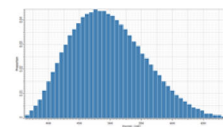

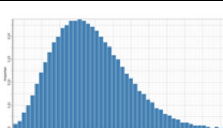
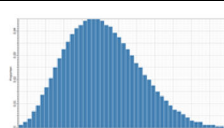
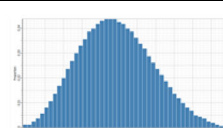
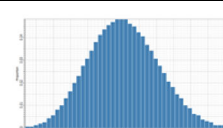
In this study, the dip angle of a reservoir layer is not investigated. However, El-Khatib (2010) found that the inclination of the reservoir layers decreases water flow rate more than it does for an oil flow rate in the waterflooding process. Therefore, it decreases water cut and increase oil recovery compared to a horizontal case. It is clear that the injectivity ratio is decreased for the inclined reservoirs as compared to the horizontal reservoirs.

Reservoirs contain two depositional sequences

In this section, the effect of reservoir heterogeneity is investigated in terms of variation of a depositional environment. Four different reservoir models, which consist of two depositional sequences, are created.

Tables 4 and 5 show the oil recovery factors of the four injection methods in these four models. Comparing results of two runs (Tables 3; 4), the oil recovery factors of model D, with two FU sequences (31.4–45.4 %), are much higher than those of the reservoir with one FU sequence (9.4–14.4 %), while there are slightly different results between the model with one CU (36.9–48.9 %) and model C with two CUs (36.4–50.8 %). In addition, the recovery factors of the WF and CO₂ flooding in model C, which contains two CU sequences, are slightly lower than those in the model, which contains one CU sequence, while the recovery factors of the LSW and LSWAG flooding in model C are higher. In the models, which contain two FU sequences, the increment of the oil recovery factor due to LSW and LSWAG flooding compared with WF (12.8–14 %) are much higher than those in reservoirs with one FU sequence (3.6–4.9 %). Consequently, we can see that the number of depositional sequences in reservoirs and

a Histograms of permeability

Aquifer	Layer 1	Layer 2	Layer 3	Layer 4
				
Minimum: 30260.4 Maximum: 33659.3 Mean: 32038.9 Std. deviation: 499.863	Minimum: 4976.49 Maximum: 6223.8 Mean: 5640.42 Std. deviation: 199.99	Minimum: 891.27 Maximum: 2086.31 Mean: 1389.94 Std. deviation: 199.98	Minimum: 362.35 Maximum: 706.89 Mean: 496.63 Std. deviation: 59.99	Minimum: 155.85 Maximum: 278.54 Mean: 200.83 Std. deviation: 19.99
Layer 5	Layer 6	Layer 7	Layer 8	
				
Minimum: 61.99 Maximum: 121.97 Mean: 83.48 Std. deviation: 9.99	Minimum: 21.34 Maximum: 50.62 Mean: 32.86 Std. deviation: 4.50	Minimum: 5.80 Maximum: 17.37 Mean: 10.83 Std. deviation: 1.99	Minimum: 0.59 Maximum: 3.70 Mean: 2.02 Std. deviation: 0.50	

b Histograms of porosity

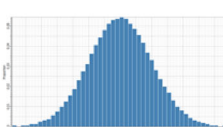

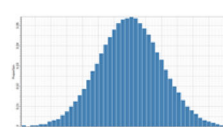

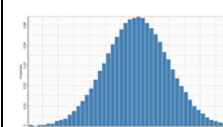
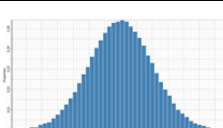
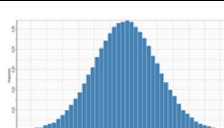
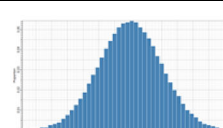

Aquifer	Layer 1	Layer 2	Layer 3	Layer 4
				
Minimum: 0.346 Maximum: 0.414 Mean: 0.38 Std. deviation: 0.0099	Minimum: 0.303 Maximum: 0.337 Mean: 0.32 Std. deviation: 0.005	Minimum: 0.253 Maximum: 0.287 Mean: 0.27 Std. deviation: 0.005	Minimum: 0.213 Maximum: 0.247 Mean: 0.23 Std. deviation: 0.005	Minimum: 0.183 Maximum: 0.217 Mean: 0.2 Std. deviation: 0.005
Layer 5	Layer 6	Layer 7	Layer 8	
				
Minimum: 0.153 Maximum: 0.187 Mean: 0.17 Std. deviation: 0.005	Minimum: 0.113 Maximum: 0.147 Mean: 0.13 Std. deviation: 0.005	Minimum: 0.073 Maximum: 0.107 Mean: 0.09 Std. deviation: 0.005	Minimum: 0.013 Maximum: 0.047 Mean: 0.03 Std. deviation: 0.005	

Fig. 4 Histograms of porosity and permeability of each layer to conduct reservoir properties of CU model

the order of layering significantly affect the recovery processes.

If the reservoirs contain two different types of a depositional sequence (FU and CU), their oil recovery factors are less than that of model C with two CU sequences but

they are higher than that of model D with two FU sequences (Table 5; Fig. 6). From these simulation results, it can be concluded that the reservoir containing at least one CU sequence performs better in terms of improving oil production. In this particular study, the reservoir that

Table 2 Average permeability and porosity of reservoirs, which contain two depositional sequences**a** Model contain one FU sequence and one CU sequence

Layers	Model A (CU–FU)		Model B (FU–CU)	
	Phi (%)	K (mD)	Phi (%)	K (mD)
1	0.32	5640	0.09	11
2	0.23	1390	0.17	83
3	0.17	83	0.23	1390
4	0.09	11	0.32	5640
5	0.09	11	0.32	5640
6	0.17	83	0.23	1390
7	0.23	1390	0.17	83
8	0.32	5640	0.09	11
9	0.38	32,039	0.38	32,039

b Model contain two FU sequences or two CU sequences

Layers	Model C (2 CU)		Model D (2 FU)	
	Phi (%)	K (mD)	Phi (%)	K (mD)
1	0.32	5640	0.09	11
2	0.23	1390	0.17	83
3	0.17	83	0.23	1390
4	0.09	11	0.32	5640
5	0.32	5640	0.09	11
6	0.23	1390	0.17	83
7	0.17	83	0.23	1390
8	0.09	11	0.32	5640
9	0.38	32,039	0.38	32,039

Table 3 Recovery factors of four injection methods in two FU models and CU models

Recovery methods	CU model	RF(*)-RF(WF) (%)	FU model	RF(*)-RF(WF) (%)	RF(CU)-RF(FU) (%)
WF	36.89	–	9.42	–	27.47
CO ₂	37.37	0.48	12.5	3.08	24.87
LSW	47.89	11	13	3.58	34.89
LSWAG	48.87	11.98	14.35	4.93	34.52

RF(*) is oil recovery factor of tertiary method

consists of two CU sequences has the highest oil recovery factor while the lowest recovery factor is observed in a single FU reservoir. The difference of oil recovery factors between secondary and tertiary injection methods is significantly dependent on a depositional sequence in reservoirs with one sequence.

Figure 7 shows a water cut curve of the field. The models, which have high oil recovery factors, have lower water cut. We can see that the reservoir containing only an

FU sequence and the reservoir having an FU sequence at the bottom (model A) favor a high water production rate and finally have high cumulative water production. Models B and C have the same water performance. Models A and D have the same water performance. The model with one CU sequence has the lowest water cut among these models.

In addition, the results of simulation show that there are two groups of reservoirs. Group 1 has a high oil recovery factor and low water production, including the reservoirs

with CU, two CU and FU–CU sequences. Group 2 has a lower oil recovery factor and very high water production, including the reservoirs with FU, CU–FU and two FU sequences.

The vertical variation of permeability causes early water breakthrough during injection processes due to low vertical sweep efficiency. It is found that two layers at the top are unswept in models B and D for the WF process. The crossflow of the injected fluid does not occur to those low-permeable layers but it does when the low-permeable layers are at the bottom (models A and C). This drawback can be overcome by applying CO₂ flooding and CO₂ LSWAG. The injected gas reduces the swept area and

increases vertical sweep efficiency by the effect of gravity, leading to mobilizing the residual oil in the top layers and increasing oil production.

Uncertainty analysis of oil recovery factor in heterogeneous reservoirs

Uncertainty analyses are run for two types of reservoir models: (1) an FU model and (2) a CU model. Table 6 shows a probability of the oil recovery factor of 10, 50 and 90 percent, which can be yielded for the four injection methods. For WF and CO₂ flooding, the different percentage between P90 and P10 is less than 0.5 % for both the CU reservoir and the FU reservoir. For LSW and CO₂ LSWAG flooding, these percentages are higher in both kinds of reservoirs. Looking at the increment of the oil recovery factor of the tertiary methods, the probability of 10, 50 and 90 % (3.1–3.4 %) is very close for CO₂ flooding with the FU model and is identical with the CU model, but it is larger for other EOR processes. Thus, the reservoir heterogeneity is the least effective for CO₂ flooding among these four injections.

Figure 8 shows the relationship between the K_v/K_h ratio and the oil recovery factor of the two reservoir types. The variation of K_v/K_h represents the vertical crossflow of fluids. There are the same trends for the four injection methods. In the FU reservoir, increasing the K_v/K_h ratio will decrease the oil recovery factor but it increases in the CU reservoir. Again, we see that the effect of the vertical

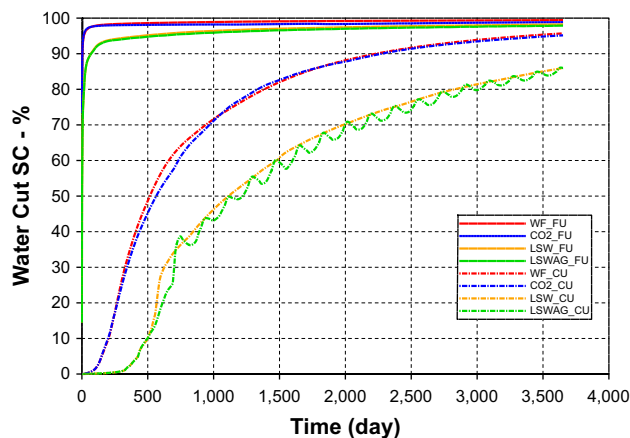


Fig. 5 Plots show water cut of models

Table 4 Recovery factors of reservoirs, which contain two FU or CU sequences

Recovery methods	Model C (2 CU)	RF(*)-RF(WF) (%)	Model D (2 FU)	RF(*)-RF(WF) (%)	RF(C)-RF(D) (%)
WF	36.39	–	31.42	–	4.97
CO ₂	36.72	0.33	32.836	1.416	3.884
LSW	49.89	13.5	44.17	12.75	5.72
LSWAG	50.84	14.45	45.42	14	5.42

RF(*) is oil recovery factor of tertiary method

Table 5 Recovery factors of reservoirs, which contain an FU sequence and a CU sequence

Recovery methods	Model A (CU–FU)	RF(*)-RF(WF) (%)	Model B (FU–CU)	RF(*)-RF(WF) (%)	RF(B)-RF(A) (%)
WF	33.83	–	34.9	–	1.07
CO ₂	33.89	0.06	35.8	0.9	1.91
LSW	46.4	12.57	47.1	12.2	0.7
LSWAG	47.89	14.06	48.1	13.2	0.21

RF(*) is oil recovery factor of tertiary method

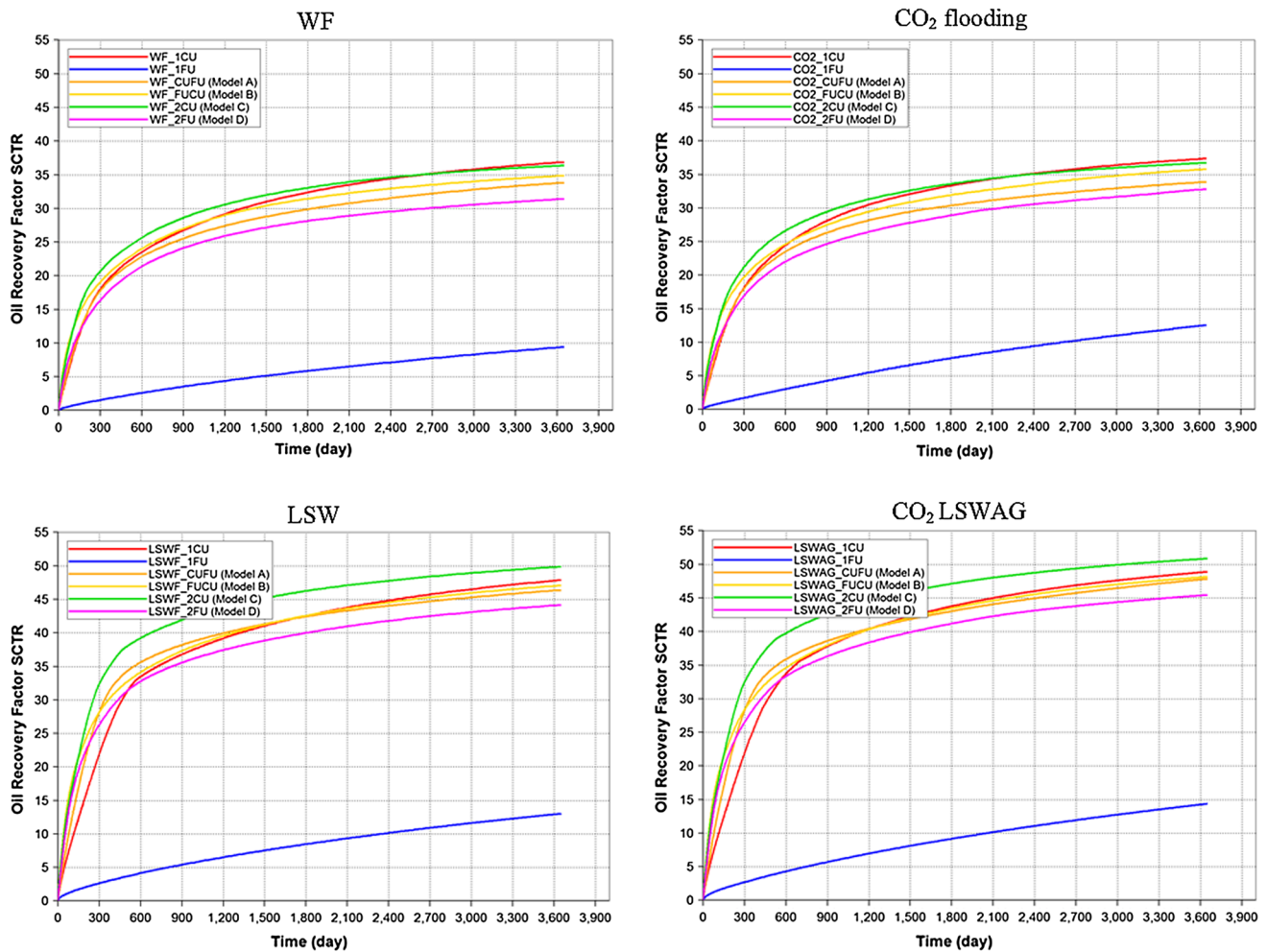


Fig. 6 Plots show recovery factors of reservoirs that contain two depositional sequences

permeability variation is clearer in LSW and CO₂ LSWAG than in WF and CO₂ flooding.

Conclusions

In simulation, a multiplayer model represents reservoir heterogeneity and an FU or CU sequence is defined as a decreasing or increasing upward permeability and porosity trend.

A new method is introduced to study the effect of reservoir heterogeneity on oil recovery processes. It can be applied for a field-scale model, which has heterogeneous reservoir properties in both directions. Permeability and porosity distributions are varied based on histograms and variograms in a geostatistic modeling process and integrated into a simulator and an optimizer for performing an uncertainty analysis.

This study shows that a depositional sequence strongly affects IOR performance. There are some observations as follows:

1. The oil recovery factors of an FU model are much lower than those of a CU model. The FU reservoirs show earlier water breakthrough, higher water production and a lower oil recovery factor.
2. The order of layering in a stratified reservoir has shown that it definitely plays a very important role in controlling the performance of a recovery process for all kinds of injection methods. It is more effective in LSW and CO₂ LSWAG methods, compared to WF and CO₂ flooding.
3. The reservoirs containing a CU, two CU and an FU–CU sequence produce at a higher oil recovery factor and lower water production than the reservoirs containing an FU, CU–FU and two FU sequences.

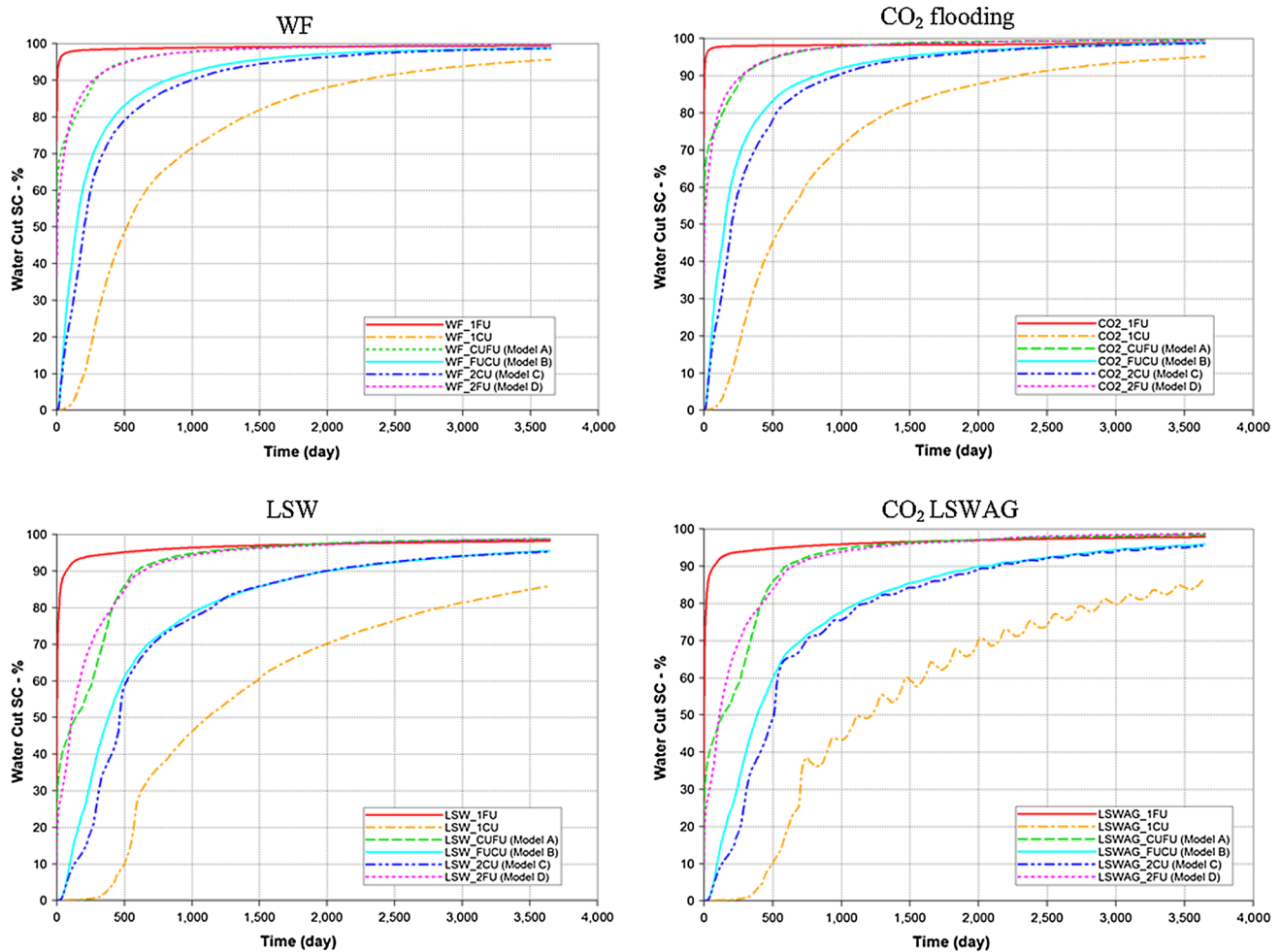


Fig. 7 Plots show water cut of reservoirs that contain two depositional sequences

Table 6 Uncertainty analysis results of four EOR methods

Recovery methods	FU model			CU model			FU model % (P90-P10)	CU model
	P10	P50	P90	P10	P50	P90		
WF	8.9	9.1	9.5	36.9	37.1	37.2	0.5	0.4
CO ₂	12.3	12.4	12.5	37.4	37.6	37.7	0.2	0.3
LSW	11.2	11.9	13.2	47.6	48.9	49.6	1.9	2.0
LSWAG	12.8	13.4	14.6	48.6	49.9	50.4	1.8	1.8
RF(CO ₂ -WF)	3.4	3.3	3.1	0.5	0.5	0.5		
RF(LSW-WF)	2.3	2.8	3.7	10.8	11.8	12.4		
RF(LSWAG-WF)	3.8	4.3	5.1	11.8	12.7	13.2		

- The vertical variation of permeability causes early water breakthrough during injection processes due to low vertical sweep efficiency. It can be improved with CO₂ flooding and CO₂ LSWAG as the high-permeable

layers are at the bottom. An oil recovery factor increases with an increase in K_v/K_h in the CU model and decreases with an increase in K_v/K_h in the FU model.

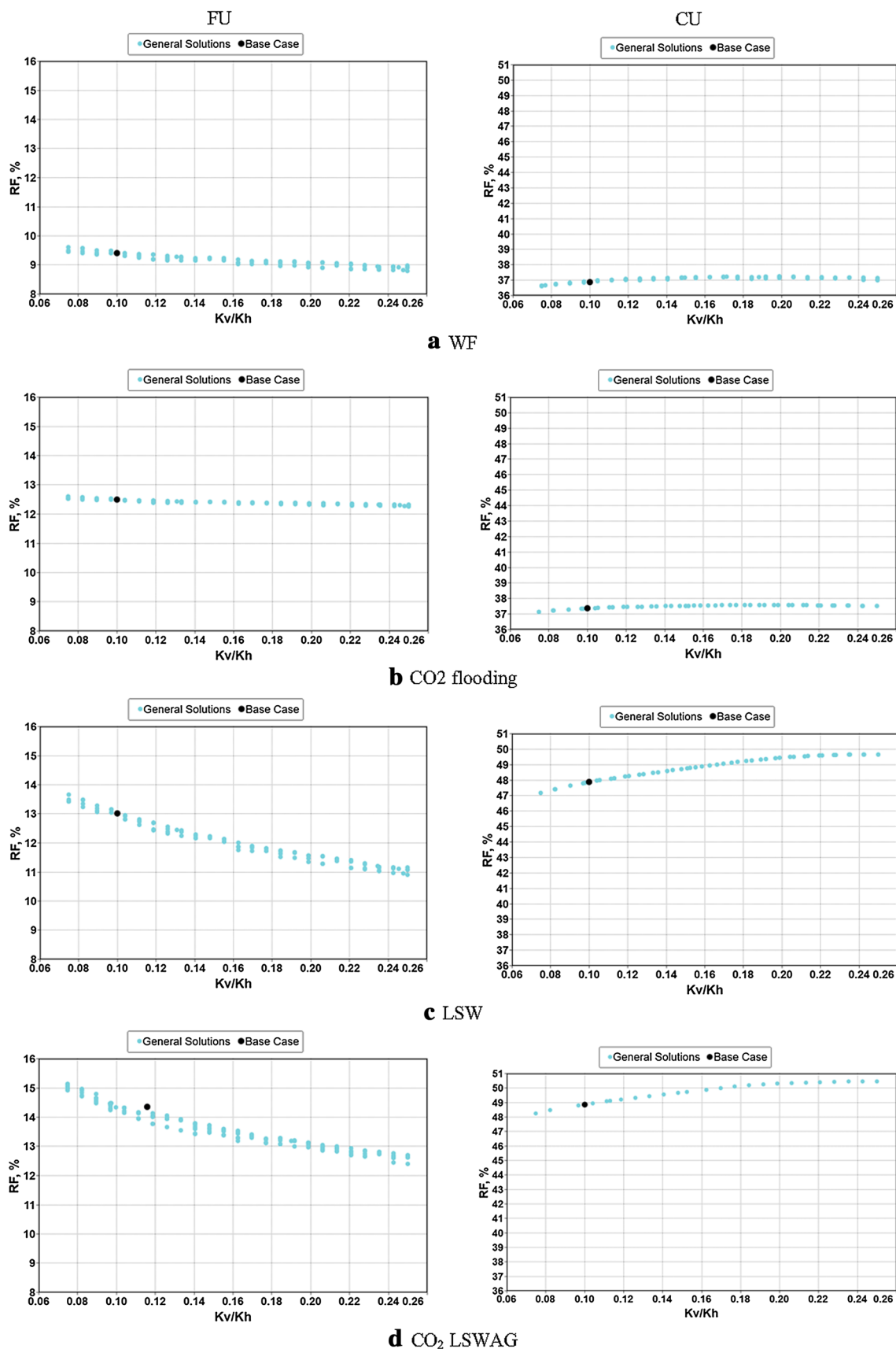


Fig. 8 Effect of vertical–horizontal permeability ratio on recovery factor (*black point* base case, *cyan points* general solutions)

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